Your ref: EPR0095

1 February 2024

Mr Tom Meares
Project Leader, AEMC
Submitted online at: www.aemc.gov.au

Dear Mr Meares

Submission: Review into electricity compensation frameworks

CS Energy welcomes the opportunity to provide a submission to the Australian Energy Market Commission's (**AEMC's**) *Consultation Paper – Review into electricity compensation frameworks* (**Consultation Paper**).

About CS Energy

CS Energy is a proudly Queensland-owned and based energy company that provides power to some of our state's biggest industries and employers. We employ almost 500 people who live and work in the Queensland communities where we operate. CS Energy owns and operates the Kogan Creek and Callide B coal-fired power stations and has a 50% share in the Callide C station (which it also operates). CS Energy sells electricity into the National Electricity Market (**NEM**) from these power stations, as well as electricity generated by Gladstone Power Station for which CS Energy holds the trading rights.

CS Energy also provides retail electricity services to large commercial and industrial customers throughout Queensland and has a retail joint venture with Alinta Energy to support household and small business customers in South-East Queensland.

CS Energy is creating a more diverse portfolio of energy sources as we transition to a new energy future and is committed to supporting regional Queensland through the development of clean energy hubs at our existing power system sites as part of the Queensland Energy and Jobs Plan (**QEJP**).

Key recommendations

The AEMC's self-initiated review is timely as the energy crisis in June 2022 highlighted a lack of confidence and uncertainty in the existing compensation regime, especially regarding the eligibility of compensation claims, how these claims would be assessed and the timeliness of compensation payments. Further, as the NEM transitions to a market with more variable renewable energy, this is likely to exacerbate issues present in the existing

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regime. Against this landscape, CS Energy supports the need to reform the electricity compensation frameworks to ensure that they are fit-for-purpose.

The Consultation Paper examines the objectives, methodologies, governance structures and administrative arrangements of the following frameworks:

- **Directions compensation** - This scheme compensates participants that are directed by the Australian Energy Market Operator (**AEMO**) to provide energy and system security services during:
    - times of system stress (when AEMO issues Lack of Reserve (**LOR**) notices or directions to maintain power system security);
    - administered pricing periods (**APPs**) (when the rolling seven-day average of spot prices breaches the cumulative prices threshold (**CPT**)); or
    - market suspension periods (**MSPs**) (when the NEM spot market is suspended by AEMO);
- **Administered pricing compensation** - This scheme is designed to maintain the incentive to supply services and compensate participants for services provided voluntarily (i.e., not under AEMO's directions) during APPs; and
- **Market suspension compensation** - This scheme is designed to maintain the incentive to supply services and compensate participants for services provided voluntarily (i.e., not under AEMO's directions) during MSPs.

Incorporating experience during and since the energy crisis in June 2022, CS Energy considers that effective and efficient electricity compensation frameworks should have the following key characteristics:

- **Fairness** - Market participants should be *fairly compensated* for the costs of energy and system security services provided, while minimising inequitable impacts on other participants and consumers. The supply of these services involves both *direct* and *indirect costs*, such as fuel costs (and scarcity), maintenance costs and reasonable losses incurred (or lost revenue) where energy-constrained plants are directed to bring forward their generation. To avoid market distortions and maintain the incentive to supply, compensation frameworks would need to adequately reflect the true costs of participants by incorporating not only the direct costs but also the indirect costs incurred when providing services;
- **Market-based** - To enhance market efficiency and the incentive to supply, the compensation frameworks should be designed to be more market-based to preserve commercial decision-making and provide relevant market signals. A market-based framework will provide crucial signals to encourage investment in under-supplied services. This can lead to a more targeted and efficient investment to increase the supply of services needed and therefore improve reliability and system security outcomes, which lowers costs for all consumers in the long run. This will become crucial to incentivising firming capability in an increasingly variable system;
- **Clarity** - The rules, eligibility and methodologies for the compensation frameworks should be set out clearly and transparently in the National Electricity Rules (**NER**) and relevant subordinate regulatory instruments. A more transparent framework enhances

predictability by allowing market participants to make a reasonable estimate of eligible compensation payments during operational timeframes. This in turn will lead to more efficient processes and outcomes;

- **Consistency** - The rules and eligibility across related compensation frameworks should be consistent to the greatest extent possible while ensuring participants are fairly compensated. Unnecessary inconsistencies can create confusion and lead to potential unintended consequences. For example, directed and non-directed dispatchable units are compensated differently during APPs not only in terms of claimable costs but also the timeliness of payment and assessment processes. This in turn leaves market participants open to the unhelpful allegations of 'window shopping' (i.e., electing to supply services based on qualifying for a preferred compensation framework); and

- **Timeliness** - To maintain market efficiency and the incentive to supply especially during periods of system stress, compensation payments to affected participants should be timely. Following the events in June 2022, payments of compensation have not been timely likely due to a lack of timeframes specifying when the assessment of claims is required to be completed. For example:

    - Compensation claims under the directions and the market suspension compensation frameworks were only finalised by AEMO in February 2023, around eight months after the event; and

    - To date, the AEMC is still assessing claims under the administered pricing compensation framework.

Based on the above-identified principles and lessons, CS Energy recommends the AEMC consider implementing the following key reforms to the compensation frameworks:

(i) **Reflect the true costs** - To avoid market distortions and maintain the incentive to supply, compensation payments need to reflect the true costs of participants when supplying services. This could be achieved by:

  a. Incorporating indirect costs through:

    - Amending the definition of 'loss of revenue'[1] under the directions compensation framework to explicitly include indirect costs associated with bringing forward generation, especially when a plant is energy-constrained; and

    - Classifying those costs associated with bringing forward generation as claimable costs under the market suspension compensation regime; and

  b. Estimating direct costs more accurately under the market suspension compensation framework by refining the benchmarking approach to better reflect commercial and operational realities. For example, benchmark values used to estimate direct costs should be formulated with input from market participants and updated every six months to ensure accuracy and relevance.

[1] Clauses 3.15.5A(g)(2) and 3.15.7B(a)(1) of the NER.

(ii) **Improve clarity and timeliness** - reforms should be undertaken to:

a. Harmonise the definitions of direct cost categories across all three compensation frameworks;

b. Enhance the codification of the indirect cost compensation process, including additional guidelines to specify the scope of compensable costs for different technologies and the level of evidence to support claims; and

c. Introduce timeframes based on the complexity of claims to incentivise the timely completion of claims and payments.

(iii) **Improve consistency and predictability** - the compensation frameworks should be aligned to the greatest extent possible while ensuring participants are fairly compensated, including:

a. Market participants should receive an automatic compensation payment based on standardised methodologies. For example, given the similarity in their objectives, the methodologies for the administered pricing and market suspension compensation frameworks should be aligned such that participants also receive automatic compensations during APPs; and

b. If the automatic payment is insufficient to cover the true costs of providing services, participants can then lodge a claim for direct and indirect costs based on processes and parameters that are standardised across all three compensation schemes.

These proposed reforms would allow directed and non-directed dispatchable units to be compensated more consistently under various compensation frameworks, especially in terms of the timeliness of the automatic payment and the assessment processes of unrecovered costs. More consistency across frameworks means that participants are likely to be more less concerned under which framework they will be compensated.

Such reforms should address concerns that participants may have more incentive to await direction by AEMO rather than providing services voluntarily during APPs and MSPs.

Additional comments specific to individual compensation frameworks

(i) Directions compensation framework

The AEMC cited the risk of under- and over-compensating participants as the rationale for moving away from the existing methodology based on historical prices[2] to a proposed benchmark approach. However, CS Energy considers the risk identified is likely to be overstated as the AEMC's analysis did not incorporate indirect costs[3] and therefore is not reflective of the true costs faced by participants when supplying energy services. A more accurate assessment will be necessary to determine if there are issues with the existing methodology that warrant any changes.

CS Energy also disagrees with the proposed benchmarking methodology as this approach does not adequately reflect the true costs of directed services and would therefore under-compensate participants. The proposed short-run marginal cost (**SRMC**) benchmarking approach using data from AEMO's Integrated System Plan (**ISP**) does not account for:

- the indirect costs of bringing forward generation if a plant is energy-constrained;
- the fuel costs incurred by participants at the time of being directed - fuel costs can fluctuate daily and even generators that have contracted fuel supply are typically exposed to fuel spot prices at the margin; and
- the increase in maintenance costs depending on how a plant is directed to run.

More importantly, resources in the NEM are getting increasingly energy-constrained mainly due to the development of battery energy storage systems (**BESS**) and pumped-hydro plants. Fossil fuel-based resources can also be energy-constrained (especially during times of system stress and high demand) as observed during the recent market suspension. For these resources, SRMC is not a meaningful concept, instead their value is determined by when a plant is available for generation.

Output from energy-constrained plants is typically designated for hedging either through a financial derivative contract (ASX or over-the-counter) or a retail contract with fixed prices. If a plant is not available when required to fulfil a contractual position or customer load because it has been dispatched due to a direction, then a participant would likely incur monetary losses due to:

- its obligation under a financial derivative (i.e., the need to pay the counterparty but missing out on higher future spot prices owing to being directed to bring forward generation); and
- the need to purchase electricity at a higher price from the NEM (especially during times of system stress) as the directed plant is unavailable to cover customer load.

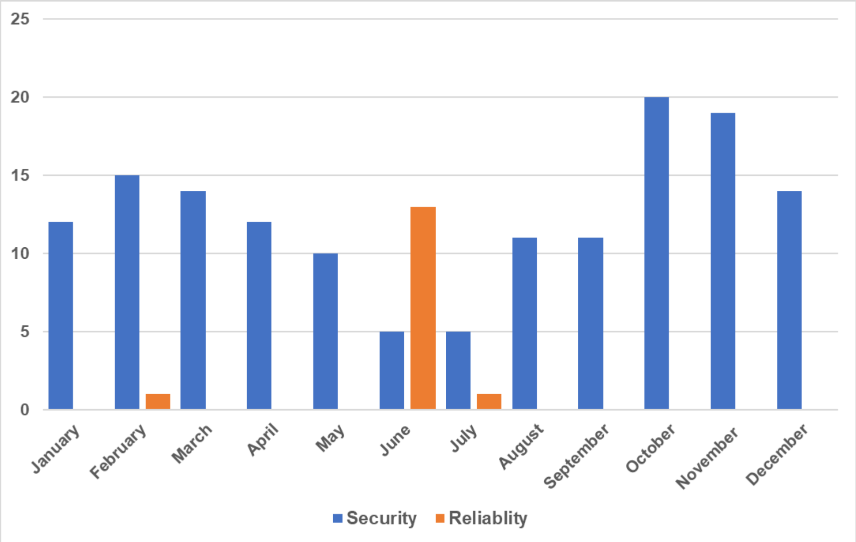
It is also important to note that indirect costs can vary widely depending on the underlying economics of different technologies. For example, BESS maximise their value by charging during periods of low spot prices and discharging during periods of high spot prices. This means that the typical approach of shadowing the costs of gas-fired plants is unlikely to adequately represent the lost revenue for a BESS. A poor compensation framework that does not adequately consider these issues could distort incentives of bids from energy-

[2] 90th percentile of spot price or frequency control ancillary services over the preceding 12 months.
[3] Specifically, indirect costs associated with being directed to bring forward generation, especially if a plant is energy-constrained.

constrained plants, especially if directions are perceived to be credible and frequent events. More work needs to be undertaken to develop methodologies that best reflect the compensation required for different technologies (including gas-fired plants, pumped-hydro and BESS) as resources in the NEM are getting increasingly energy-constrained.

Further, the Consultation Paper has focused primarily on the compensation relating to directions issued for energy services to maintain reliability (during LOR conditions). However, directions issued to maintain system security are substantially more frequent than those for energy services (Figure 1). CS Energy considers more work is necessary to assess whether the compensation methodology for system security related directions remains appropriate as the NEM transitions to a system increasingly dominated by variable renewable energy, and the expectation of a market value placed on the provision of security services.

Figure 1 Number of AEMO directions across the NEM by type - 2022



Source: CS Energy's analysis of AEMO data.

CS Energy strongly disagrees with deliberately under-compensating participants for directed services as raised in the Consultation Paper. While this may be superficially appealing in the short-run, it will create market distortions by undermining the investment signals and revenue adequacy needed to provide essential system security and reliability services in the NEM, which in turn increases costs for consumers in the long-run.

(ii) <u>Administered pricing and market suspension compensation frameworks</u>

The Australian Energy Regulator (**AER**) conducted a review of generator behaviour during the APPs in June 2022. It alleged that some generators engaged in conduct that contributed to AEMO issuing directions but noted that these participants are likely to have had a reasonable cause to withdraw capacity given the circumstances.

On this basis, the AER concluded that the objective of the administered pricing compensation regime is inadequate and proposed the following amendments:

- Removing commercial considerations as a reasonable cause for contributing to a direction in clause 4.8.9 (c2);

- Imposing a positive obligation on generators to continue offering capacity at times of market stress (i.e., LOR 2 and 3 conditions during APPs); and
- Obliging generators to use available price bands during APPs.[4]

The AER's proposed blunt approach to impose mandatory obligations in relation to the objective is, in CS Energy's opinion, likely to result in unintended consequences including:

- Undermining the efficiency of the NEM - The NEM is an energy only market and imposing a capacity obligation (particularly without compensation) would distort market and therefore investment signals, and undermine the efficient operation of the NEM.
- Reducing the liquidity in electricity contract markets - As noted, due to volatility in the NEM, generators typically hedge their output. During market interventions, generators have limited control over their energy-constrained plants and face severe risk that their output is dispatched at a time/volume not of their choosing. This creates a substantial financial risk as generators would need to pay their counterparty and could miss out on future spot prices due to being directed. In these circumstances, imposing a capacity obligation would amplify this risk as it requires generators to provide capacity even when their output has been designated for hedging. Therefore, such an obligation creates a disincentive for generators to offer their output through derivatives, which reduces the liquidity in electricity contract markets.

CS Energy considers, rather than the objective being deficient, the shortcomings lie with the incentives stemming from the design of the compensation frameworks as well as the market settings that were in place in June 2022. These include:

- The various compensation frameworks are scattered throughout the NER with dissimilar mechanisms applying for each different market circumstance. This makes it challenging for participants to be:
    - Clearly aware of the type of compensation for which they are eligible; and
    - Able to make a reasonable estimate of those reimbursements as part of the commercial decision-making process during operational timeframes.
- There are also countless discrepancies and inconsistencies across the compensation frameworks that create confusion and lead to potential unintended consequences. Directed and non-directed dispatchable units are compensated differently during APPs and MSPs not only in terms of claimable costs but also the timeliness of payment and assessment processes. Specifically:
    - Directed units are compensated an automatic payment (based on historical prices[5]) and can lodge a claim for direct costs (but not explicitly indirect costs[6]) with AEMO if the automatic payment is insufficient to cover their costs;
    - Non-directed units during APPs are settled at spot prices that are capped at the administered price cap (**APC**) and the administered floor price (**AFL**). Participants who made a net loss during the eligible periods can apply to the AEMC for compensation for direct and indirect costs; and

[4] AER, June 2022 market events report, December 2022.
[5] 90th percentile of spot price or frequency control ancillary services over the preceding 12 months.
[6] It can be argued that the "loss of revenue' provisions (in clauses 3.15.5A(g)(2) and 3.15.7B(a)(1) of the NER) cover certain elements of indirect costs such as concepts of forgone forward-looking revenue.

  - Non-directed units during MSPs are settled using the market suspension schedule. Participants who made a loss will be compensated automatically based on benchmarking approach using values from AEMO's ISP. If participants still incur a loss after the automatic payment, then they can lodge a claim for direct costs (but not other costs) with AEMO.

  In addition to creating uncertainty, these discrepancies also leave participants open to the unhelpful allegations of 'window shopping' i.e., electing to supply services based on qualifying for a preferred compensation framework;

- Due to high commodity prices in June 2022, the then APC of $300/MWh was insufficient to cover even the SRMC of coal-fired and gas-fired plants in most circumstances. This was acknowledged by the AER as a factor that contributed to generators choosing to withdraw their capacity during the APPs.[7] However, the APC has since been increased to $600/MWh; this level should better reflect the actual costs that generators face during times of system stress and therefore contributes to maintaining the incentive to supply during APPs; and

- Clause 3.9.7(b) of the NER precludes a constrained-on[8] generator from receiving compensation when the spot price is less than its dispatch offer price. This can serve as a disincentive for generators to make capacity available as they may incur a loss that is not compensable when constrained-on, especially during times of system stress.

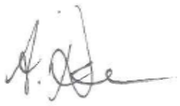
  To mitigate the disincentive created by clause 3.9.7(b), constrained-on generators should be allowed to apply for compensation for direct and indirect costs.

Conclusion

The compensation frameworks have several shortcomings that likely contribute to undesired outcomes. CS Energy supports the AEMC's review and suggests that the frameworks can be enhanced by ensuring they reflect the true costs of participants. Further benefit would result from improving the clarity and timeliness of the frameworks and ensuring their consistency and predictability. The directions compensation framework also needs to consider the provision and value of system security services. CS Energy believes this proposed approach will lead to much more efficient outcomes for the market and consumers.

If you would like to discuss this submission, please contact Wei Fang Lim, Market Regulatory Manger, at wlim@csenergy.com.au or on 0455 363 114.

Yours sincerely



Dr Alison Demaria
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[7] AER, June 2022 market events report, December 2022.
[8] In this context, to avoid exceeding a power system limit, a binding constraint in the NEM dispatch engine would increase the output of a generator above the volume limit specified by its dispatch offer bids.